Decision **REVISED DRAFT DECISION OF COM. WOOD (Mailed 7/2/2002)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system.	Rulemaking 00-10-002 (Filed October 5, 2000) Phase 2

INTERIM OPINION ON DEMAND BIDDING PROGRAM

1. Summary

We authorize limited changes to the demand bidding program (DBP). The changes transition DBP to a reliability program, and increase the feasibility of its operation for Summer 2002.

As revised, requests and bids are not limited to three blocks of four hours each, but may be for any hours of identified need. The program may be operated on a day-ahead or day-of basis. The price is fixed at $0.35/per kilowatt-hour (kWh). Utilities will evaluate offers, accept or reject each bid, and pay participants based on performance. DBP expenses may be tracked in the memorandum account for total program expenses. The annual program total cost cap for Southern California Edison Company (SCE) is raised by $10 million.

Each utility shall file an advice letter within five days of the date of this order to implement these changes. The changes will be effective in five days

unless suspended by the Energy Division Director. This proceeding remains open to address two petitions for modification.

2. Background

In our decision on Phase 2 matters, we kept this proceeding open for further consideration of the DBP. (Decision (D.) 02-04-060, Ordering Paragraph 21.) In particular, we said:

> "…we keep this proceeding open to examine the future of the DBP. DWR [Department of Water Resources] may or may not be able to fund the DBP for Summer 2002. We want continuation of this program, or a smooth transition to a similar program, because this or a similar program provides unique flexibility for customer participation and payment based on performance. Customers are familiar with DBP, and both hardware and software are in place for its implementation. The Assigned Commissioner and Administrative Law Judge should seek comment on alternatives as appropriate for our further consideration and resolution before this summer."
> (D.02-04-060, mimeo., page 54.)

Comments on the future of DBP and alternatives were sought by Ruling dated May 14, 2002. On May 20, 2002, comments were filed and served by Pacific Gas and Electric Company (PG&E), SCE, San Diego Gas and Electric Company (SDG&E) and the Office of Ratepayer Advocates (ORA). On May 24, 2002, reply comments were filed and served by PG&E, SCE and ORA.

Utilities largely recommend against wholesale redesign of DBP and suggest several limited changes. Utilities state that they are not procuring electricity, and do not have access to the information necessary to determine when to activate the program or how much load relief to request. SCE recommends a single DBP price rather than the current range of four prices in two tiers. Utilities generally oppose revival of the Voluntary Demand Response Program (VDRP) or other alternatives to DBP.

ORA recommends resurrecting the California Independent System Operator (ISO) Discretionary Load Curtailment Program (DLCP) and linking DLCP with the Optional Binding Mandatory Curtailment (OBMC) program. ORA suggests adding an initial DBP price at the Federal Energy Regulatory Commission (FERC) current wholesale spot market price cap of $0.09187/kWh.

3. Demand Bidding Program

We make limited changes to the DBP. The revised program is contained in Attachment A.

We agree with utilities that relatively minor modifications to DBP are preferable to a wholesale redesign of DBP, reactivation of VDRP, or development and adoption of a new program (such as linking OBMC with DLCP). DBP is essentially up and running. Customers have signed DBP agreements, are familiar with the basics of the program, and are prepared to make load curtailment bids immediately. One or more websites are in place for DBP implementation.

On the other hand, major changes to DBP, reactivation of VDRP, or development of a new program would require relatively more customer education, and may engender customer resistance (e.g., if customers view changes as providing inadequate additional value for the corresponding inconvenience or burden). Further, significant program changes would require enrollments in the revised or new program, may involve additional expenses for system modifications, and would necessitate time for implementation that is unavailable given the arrival of Summer 2002.

3.1. Time Blocks, Program Initiation, and Use During Stages 2 and 3

The original DBP employed three four-hour time blocks for bids and operation. This was in part a balance between program simplicity (e.g., known, limited parameters) and complexity (e.g., infinite possibilities to allow more precise matching of supply and demand). It is now reasonable to remove the limit of three four-hour time blocks. ISO and utilities should be permitted to seek load relief in any combination of hours that will best match supply and demand. ISO and utilities may continue to employ three four-hour time blocks if that reflects their best judgment regarding use of the program. While we do not go as far in program redesign as recommended by ORA, this modest change, to be implemented at ISO's and utilities' discretion, provides a reasonable increase in flexibility to potentially better match supply and demand for Summer 2002.

We agree with utilities that they are not in a position to determine when DBP should be called. We adopt SCE's recommendation that DBP events should be activated by the ISO. This is consistent with our transitioning DBP to a reliability program, as discussed more below, given ISO's role in monitoring operating reserves.[1] To promote clarity, the revised DBP will specifically state that ISO will notify utilities when additional load relief is needed.

---

[1] The ISO is responsible for monitoring the state's generation operating reserve, and notifying market participants and state agencies when an emergency is likely, or is called. The ISO declares a Stage 1 emergency when forecast or actual operating reserves are less than 7% of available capacity. A Stage 2 emergency is declared when forecast or actual operating reserves are less than 5% of available capacity. A Stage 3 emergency is declared when forecast or actual operating reserves are less than 1.5% of available capacity. The ISO may call for rotating outages during Stage 3 emergencies.

We accept the recommendations of ISO and utilities that DBP is best triggered by an ISO Alert Notice. According to ISO, a 24-hour Alert Notice is issued if "there is a potential for firm load curtailment within the next 24 hours based on forecasted load and resources." (ISO Procedure E-508, page 3, Exhibit A to June 21, 2002 ISO Comments.) ISO recommends that the DBP timetable be modified to permit more flexibility, however, since alerts might be issued after 2 p.m. the day before.

We agree that more flexibility is needed. In particular, we adopt use of an ISO Alert Notice to trigger DBP, but do not limit the solicitation of bids to the afternoon of the day before. Rather, bids may be solicited on shorter timeframes if real time operations by ISO do not permit more notice to utilities and customers. We adopt a one-hour timeframe for utilities to solicit bids, with an additional hour to evaluate bids and notify customers of the results. We do not require automatic rejection of bids that might be submitted after the one-hour deadline, but utilities are not obligated to evaluate late bids equally with timely bids, and should take current conditions into account in evaluating late bids.

We continue program focus on Stage 2 and 3 events. (See, for example, Executive Order D-39-01 dated June 9, 2001, revised June 11, 2001, first ordering paragraph; also D.01-07-025, mimeo., page 1.) We specifically limit DBP use to periods of forecast or actual Stage 2 or Stage 3 emergencies to the fullest extent reasonably possible, thereby promoting targeted use of the program. We decline to authorize its use during normal operations or Stage 1 events since, as discussed more below, we intend DBP to fill reliability needs and not be used as a price response / mitigation program. Moreover, implementing DBP during Stage 1 when potentially less costly resources are available would not be reasonable.

ISO states that it does not predict Stage 2 and 3 events the day before and is troubled by any requirement that it estimate the amount of DBP resources that each utility should accept. We recognize that an ISO Alert Notice only provides notice of the potential for firm load curtailment within the next 24 hours. We understand that the 24-hour Alert Notice neither specifies whether the event is expected to be a Stage 1, 2 or 3 emergency, nor estimates the amount of resource shortage. Nonetheless, we expect utilities to use reasonable judgment to solicit and accept bids only when Stage 2 or 3 are likely. For example, after an ISO Alert Notice, utilities may delay bid solicitation and evaluation until Stage 2 or 3 are forecast or imminent in order to permit proper focus of DBP on Stage 2 and 3 events.

Further, as part of bid evaluation we expect utilities to accept DBP bids only after all other less expensive resources are used to the fullest extent feasible and reasonable. For example, traditional interruptible programs (where capacity payments are incurred whether or not curtailments are initiated) should be used before relatively more expensive programs, such as DBP.

Finally, we expect utilities to use their best judgment to accept bids only within estimated need. Utilities should reject some or all bids if DBP resources are otherwise unnecessary to reasonably balance supply and demand to satisfy ISO reliability criteria.

3.2. Transition to Reliability Program

We agree with utilities that a modified DBP can fill a niche for a voluntary, non-penalty-based, day-ahead, reliability program. DBP initially served many goals. One goal was as a price responsive program that could potentially mitigate against high wholesale prices. As SCE points out, however, DBP has not operated as originally intended because the market has not exhibited the price volatility that makes a price response / mitigation program necessary and desirable. Nonetheless, DBP can still deliver value in a portfolio of load management programs by transitioning to a reliability program.

In making this transition to a reliability program, we also seek alternative funding and a utility role consistent with that funding. We continue utility monitoring of DBP curtailments as provided in the current program, but add utility evaluation of bids and payment to DBP participants based on performance. Utility funding will provide resources to promote program use, while utility evaluation of bids will increase the utility's role. Each utility may record DBP payments in its interruptible program memorandum account for subsequent recovery. We modify the pricing structure to provide necessary feasibility for utility evaluation of bids.

We agree with SCE that a single incentive level will promote transforming DBP into a reliability program. A range of prices focuses the program on price response and price mitigation, while a single price promotes using the program for system reliability. A range of DBP bids at different prices also requires bid evaluation at each price in relation to all other options at each price. DWR has information on all resources, but, as utilities point out, utilities currently do not have access to sufficient information to make that judgment regarding all possible options. A single price, however, will allow each utility to determine which DBP bids to accept or reject for reliability on each system, consistent with our goals of transforming the program and increasing each utility's role in the program. At the same time it will permit utilities to use cost information relative to the programs they operate for the purpose of implementing the least costly options (e.g., dispatching programs with a fixed capacity payment when those programs are less costly for incremental operation than DBP operation).

Further, ISO does not have the same incentives to minimize total costs as does each utility. Ratepayer funding of this program requires that utilities have the ability to exercise some judgment about its use.

Therefore, we adopt SCE's recommendation to employ a single price. We set that price at $0.35/kWh, the same level we adopted for the VDRP. (D.01-04-006, mimeo., page 31.) As with the VDRP price, this balances a range of possible prices addressed by parties, from the low end (the level of the current FERC wholesale spot market price cap ($0.09187/kWh) recommended by ORA) to the high end (prices and penalties for mandatory curtailment programs).[2] It reflects the voluntary nature of the program, the benefit of advance notice provided by this program compared to other programs, the absence of penalties, and a price level below that of existing mandatory curtailment programs.

Moreover, a single price at a reasonable level removes the opportunity for participants to manipulate the system to their advantage (e.g., by participants limiting offers to only those at the highest price). A single price at a reasonable level balances competing interests and promotes efficiency. Parties may use the expedited methods discussed in our Phase 1 order to seek adjustment of the price, if necessary. (D.01-04-006, mimeo., pages 31-32.)

Utilities should use first-come first-served as a primary criterion for accepting a bid, taking past non-performance or non-compliance by the customer into account. We adopt utilities' proposal for implementing a fair mechanism for

---

[2] As ORA observes, paying more than $0.092/kWh is moot if supply-side resources are available at the price cap or less. On the other hand, if the cap results in a shortage, it is reasonable to pay customers more to use less (which ORA analogizes to the 20/20 conservation program).

non-performance and non-compliance measurement based on preliminary meter data for a series of consecutive events. As discussed above, utilities must also apply reasonable judgment to accept bids only within estimated need, as well as employ less expensive programs first, to the extent feasible.

We also adopt utilities' recommendation to limit customer bids to one per day in consecutive hours, with a minimum duration of 2 hours. A multitude of disjointed bids from a single customer would otherwise unreasonably complicate the program.

Further, we agree with utilities that accepted bids should not subsequently be cancelled. Customers with accepted DBP bids commit to a demand curtailment. They should be compensated for that commitment based on their actual performance regardless of whether the ISO later cancels the Alert Notice.

Finally, we agree with utilities that customers should not be permitted to simultaneously participate in multiple programs with the potential of being paid twice for a single event. Thus, just as we preclude DBP customers from participating in the ISO's Demand Relief Program and Ancillary Services Load Program, we similarly preclude their participation in the California Power Authority's new Demand Reserves Program.

3.3. Interruptible Program Cap

SCE proposes that DBP incentive payments not be included in the interruptible and curtailment program total funding cap. SCE argues that the Commission did not consider these payments when the cost cap was set, and that SCE projects it will be close to, or exceed, the cap before the conclusion of Summer 2002. SCE asserts that if DBP is called on frequently this summer, SCE could be forced to suspend all interruptible program activities during a time of critical need as the cost cap is reached.

We decline to adopt SCE's proposal. SCE's proposal is effectively an "infinite" cost cap for one program. This could have the undesirable effect of encouraging use of one program over others unrelated to the merits or individual costs of each program. Further, the cost cap is a "method to apply some guidance and control to these programs without adopting unreasonable expectations or constraints." (D.02-04-060, mimeo., page 21, footnote 9.) The cap prevents "these programs from spiraling out of control if conditions unexpectedly and dramatically change…" (D.02-04-060., mimeo., pages 20-21.)

VDRP was included in the original cost cap. (D.01-04-006.) VDRP was replaced by DBP, but the cost cap was not reduced to reflect DWR funding of DBP. (D.01-07-025.). The cost cap was subsequently reduced for all utilities consistent with a revised overall program goal of 2,500 MW. (D.02-04-060.) PG&E and SDG&E do not argue that there was a failure to consider DBP in the original or revised cost cap. SCE does not convincingly show that there was such failure.

Nonetheless, SCE is concerned that it may approach its annual cost cap of $137.5 million.[3] To address this limited concern, we raise SCE's cost cap by $10 million, to a total of $147.5 million. This increase will fund approximately

---

[3] SCE's monthly reports include estimates of total expenses for 2002 and the total program cost cap. In three out of the last four months the estimates have been in the range of $120 million. For example, SCE's monthly report dated February 7, 2002 estimates total expenses for 2002 of $120.0 million with the original total program cost cap of $275.0 million. SCE's monthly report dated March 7, 2002 estimates 2002 expenses of $121.7 million with a cost cap of $275.0 million. SCE's monthly report dated April 8, 2002 estimates 2002 expenses of $133.8 million with a reduced cost cap of $137.5 million. (The cost cap was reduced in D.02-04-060.) SCE's monthly report dated May 21, 2002 estimates 2002 expenses of $119.3 million with a cost cap of $137.5 million.

47 MW of DBP resources for 10 hours per day for 60 non-holiday weekdays.[4] This is a reasonable amount for Summer 2002 without being excessive.

We remind parties "that any party may file a timely pleading if, in the party's judgment, program limits should be adjusted upward or downward (e.g., a utility may file an application; a utility or party may file a petition for modification)." (D.02-04-060, mimeo., page 21.) We adopted a requirement for the filing of monthly reports by utilities to help utilities, parties and the Commission monitor whether cost caps are being approached, and we allowed for acting on an emergency basis to increase megawatt or dollar limits if necessary. (D.01-04-060, mimeo., page 80.)

Under no circumstances should a utility be forced to suspend all interruptible program activities based on its reaching the cost cap. Rather, a utility must file a timely pleading seeking a further increase if it forecasts that it may reach the cost cap. The utility should file that pleading with adequate time for parties to comment and the Commission to act in the normal course of Commission business. If necessary, however, the Commission will act on an emergency basis. Any utility's failure to follow this procedure in a timely way, resulting in the utility suspending interruptible programs during a system emergency and thereby jeopardizing the health, safety and welfare of the state's citizens, would be unreasonable absent a very compelling reason to the contrary.

---

[4] 47 MW for 10 hours per day for 60 non-holiday weekdays (12 weeks) is 28,200 megawatt-hours. At a payment of $0.35/kWh, the total cost would be $9.87 million. SCE currently has 96 customers representing 133 service accounts subscribed to DBP. The aggregate maximum demand of these participants is 211 MW. The minimum potential load reduction for these customers, under the terms of the DBP tariff, is 16 MW.

SCE does not request an increase in its interruptible program limit of 1,375 MW. No party comments on any necessary change in the capacity limit. We do not adopt an adjustment in SCE's total interruptible program megawatt limit.

3.4. Cost Recovery

SCE also recommends that the Commission make an explicit finding that all incentive dollars paid by utilities are *per se* reasonable upon verification of the customer's actual load reduction. This would be reasonable, according to SCE, since ISO triggers program activation and event scope rather than the utility. We decline to make this finding. Rather, we expect utilities in the revised DBP to take more than a purely passive role in DBP operation.

Moreover, we have already provided that reasonable implementation costs not otherwise recovered through existing rates, or offset by revenues, are subject to later recovery. As we said in both the Phase 1 and Phase 2 orders, during this continuing State of Emergency in the California electricity market:

> "We will review the balance in each memorandum account for reasonableness before authorizing recovery but, absent incompetence, malfeasance, or other unreasonableness, we would expect to authorize full recovery of all dollars spent by the utilities for these programs to get California through this crisis." (D.01-04-006, mimeo., page 78; also see D.02-04-060, mimeo., page 21.)

Utilities need no additional assurance of recovery at this time.

4. Need for Expedited Consideration

Rule 77.7(f)(9) of the Commission's Rules of Practice and Procedure provides in relevant part that:

> "…the Commission may reduce or waive the period for public review and comment under this rule…for a decision where the Commission determines, on the motion of a party or on its own motion, that public necessity requires reduction or waiver of the 30-day period for public review and comment. For purposes of this subsection, "public necessity" refers to circumstances in which the public interest in the Commission adopting a decision before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full 30-day period for review and comment. "Public necessity" includes, without limitation, circumstances where failure to adopt a decision before expiration of the 30-day review and comment period…would cause significant harm to public health or welfare. When acting pursuant to this subsection, the Commission will provide such reduced period for public review and comment as is consistent with the public necessity requiring reduction or waiver."

We balance the public interest in quickly modifying the DBP against the public interest in having a full 30-day comment cycle on the proposed modification. We conclude that the former outweighs the latter. The DBP will protect public health, safety and welfare in Summer 2002 by promoting system reliability. Any delay in implementing a revised DBP jeopardizes public health, safety and welfare by increasing the risk of customers experiencing a less reliable system, including the potential of rotating outages. We seek valuable public review of, and comment on, the proposed change, and find that a reduced period balances the need for that input with the need for timely action.

5. Comments on Draft Decision

On June 18, 2002, the draft decision of Presiding Officer and Assigned Commissioner Wood on this matter was filed and served on parties in accordance with Section 311(g)(1) of the Public Utilities Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed and served on

June 21, 2002 by ISO and jointly by PG&E, SCE and SDG&E. Reply comments were filed and served on June 25, 2002 by ISO and jointly by PG&E, SCE and SDG&E. We incorporate changes based on comments and reply comments. In particular, we incorporate day-of features in the program, and include joint utilities recommendations regarding nonperformance measurement, limiting submission of bids to one per day, decline simultaneous participation in the California Power Authority's Demand Reserves Program, and provide five days for utilities to file and serve advice letters with tariffs in compliance with this order.

On July 2, 2002, the revised draft decision of Presiding Officer and Assigned Commissioner Carl Wood on this matter was filed and served on parties. Comments were filed and served on July __, 2002 by ____. Reply comments were filed and served on July ___, 2002 by ____.

Findings of Fact

1. Relatively minor changes to DBP are preferable to a wholesale redesign of DBP, reactivation of VDRP, or development and adoption of a new program since DBP is up and running, agreements are in place, customers are familiar with DBP, and customers are prepared to make load curtailment bids immediately while, in contrast, major changes or a new program would require education, may face resistance, would require new enrollments, may involve new costs, and would require time that is unavailable.

2. Utilities are not in a position to determine when DBP should be called.

3. Flexibility to balance supply and demand is increased by (a) removing the limitation that ISO and utilities must employ three four-hour time blocks for DBP, and (b) allowing implementation on a day-of as well as day-ahead basis.

4. DBP has not operated as a price response/mitigation program because the market has not exhibited substantial price volatility since DBP was adopted.

5. A modified DBP can fill a niche for a voluntary, non-penalty-based, day-ahead, reliability program.

6. A single incentive level promotes transforming DBP to a reliability program.

7. Utility funding will provide resources to promote feasible program use, while utility evaluation of bids will increase the utility's role consistent with utility funding and transition of DBP to a reliability program.

8. A single DBP price at $0.35/kWh balances a range of possible prices, reflects several factors (e.g., the voluntary nature of the program, the benefit of advance notice, the absence of penalties, and a price level below that of existing mandatory curtailment programs), and removes the opportunity for participants to manipulate the system to their advantage.

9. DBP customers should not be permitted to simultaneously participate in multiple programs with the potential for being paid twice for a single event, such as ISO's Demand Relief Program, ISO's Ancillary Services Load Program, and California Power Authority's new Demand Reserves Program.

10 SCE is concerned that it may approach its annual cost cap of $137.5 million.

11. A cost cap increase of $10 million for SCE will fund about 47 MW of DBP load relief for 10 hours per day for 60 non-holiday weekdays.

12. Any utility's failure to follow adopted procedures to increase the interruptible program cost cap in a timely way, resulting in the utility suspending interruptible programs during a system emergency and thereby

jeopardizing the health, safety and welfare of the state's citizens, is unreasonable absent the utility presenting a very compelling reason to the contrary.

13. Utilities need no further assurance of cost recovery at this time.

14. The public interest in quickly modifying the DBP outweighs the public interest in having a full 30-day comment cycle on the draft decision.

Conclusions of Law

1. The DBP should be revised to permit ISO to employ DBP as needed in other than three four-hour time blocks on either a day-ahead or day-of basis.

2. DBP should be transitioned to a reliability program at a single incentive payment level of $0.35 / kWh.

3. DBP should be funded by utilities and DBP expenses should be allowed to be recorded in each utility's interruptible program memorandum account.

4. Each utility should evaluate DBP bids within its service area and accept bids from reliable customers (taking past performance into account) on a first-come first-served basis, also considering need and cost.

5. SCE's interruptible and curtailment program cost cap (D.02-04-060, Ordering Paragraph 19) should be increased by $10 million, to a total of $147.5 million.

6. The period for public review and comment on the draft decision should be reduced.

7. This proceeding should remain open.

8. This order should be effective today so that the revised DBP may be implemented without delay to protect public health, safety and welfare.

INTERIM ORDER ON DEMAND BIDDING PROGRAM

IT IS ORDERED that:

1. Within five days of the date of this order, respondent utilities Pacific Gas & Electric Company, Southern California Edison Company (SCE), and San Diego Gas & Electric Company shall each file and serve an advice letter with revised tariffs. Each advice letter with revised tariffs shall implement revisions to the demand bidding program described in this order and in Attachment A. Each advice letter with tariffs shall be in compliance with General Order 96-A. Each advice letter with tariffs shall become effective five days after filing, unless suspended by the Energy Division Director. If any advice letter with accompanying tariffs is suspended by the Energy Division Director, the advice letter and tariffs shall become effective upon the date the Energy Division Director determines that the tariffs comply with this order. The Energy Division Director may require a respondent utility to amend its advice letter and tariffs to comply with the orders herein. Respondent utilities shall work with the Energy Division Director and staff to prepare advice letters and tariffs that are consistent with the orders herein, and reasonably consistent among utilities.

2. The total annual program dollar limit for SCE (Decision (D.) 02-04-060, Ordering Paragraph 19) is increased by $10 million to a total of $147.5 million.

3. This proceeding remains open solely to address the February 20, 2002 petition for modification of D.01-09-020 filed by Dr. Lee F. Walker and the

May 22, 2002 petition for modification of D.02-04-060 filed by California Industrial Users and California Large Energy Consumers Association.

This order is effective today.

Dated _______________, at San Francisco, California.

ATTACHMENT A
DEMAND BIDDING PROGRAM

The Demand Bidding Program (DBP; see Decision 01-07-025; Attachment A) is replaced with the following program:

2.6 Demand Bidding Program (Revision 1.0)

2.6.1 The Offer

2.6.1.1 The California Independent System Operator (ISO) shall notify each utility distribution company (UDC) when demand bidding program (DBP) load relief may be needed. For purposes of this program, the triggering event will be an ISO 24-hour Alert Notice, which is the first indication that there potentially will be less than 7% operating reserves within the next 24 hours. UDCs will trigger a day-ahead event based on receipt of this Alert Notice from the ISO by 2pm on the day preceding an event, and either a day-ahead or a day-of event based on an Alert Notice from the ISO after 2 pm on the day preceding or day of an event. UDCs shall not solicit bids from DBP participants until the UDC reasonably expects Stage 2 or Stage 3 to be forecast or implemented sometime within the 24-hours following the ISO Alert Notice.

2.6.1.2 Participating customers shall submit bids to a DBP website. UDCs may also notify customers via the internet and other means of communication as needed of DBP events on a day-ahead basis.

2.6.1.3 Each DBP participant shall have one hour from notification of DBP bid solicitation to submit a bid. A bid may be submitted beyond one hour after notification of bid solicitation, but the utility need not give equal consideration to late and timely bids. In evaluating late bids, the utility must consider then current conditions, including previous acceptance or rejection of timely bids submitted within the first hour. Bidding shall be accepted for non-holiday weekdays only.

2.6.1.4 Participants shall indicate the amount of kilowatt (kW) curtailment they are offering and the specific times. Bids shall be submitted with a minimum duration of two hours, with no more than one bid per day.

2.6.1.5 DBP load reductions shall be paid at the rate of 35 cents ($0.35) per kilowatt-hour.

2.6.2 DBP Offer Evaluation and Confirmation

2.6.2.1 Within one hour after the bid submission deadline, each UDC shall evaluate each bid timely submitted within its service area, accept or reject each bid, and notify each bidder of the result.

2.6.2.2. A primary criterion for accepting bids shall be reliable offers (taking bidder past performance and compliance into account) on a first-come first-served basis. If preliminary meter data indicates that a customer is not entitled to receive compensation for three consecutive events, such customer should thereafter be precluded from participating in the following two operations of the DBP.

2.6.2.3. To the fullest extent reasonably possible, each utility shall also limit bid acceptance to use of DBP curtailments only during forecast or actual Stage 2 and 3 events, shall not accept DBP bids unless and until all resources reasonably known to be less expensive are first employed (e.g., traditional interruptible programs), and shall limit bid acceptance to only the amount of kW needed to satisfy ISO reliability criteria.

2.6.3 DBP Performance Verification and Payment

2.6.3.1. The UDC will track the curtailment of participating customers. The UDC will review the performance meter data against the accepted bids and calculate the payment due to the participating customers, with payments based on actual performance.

2.6.3.2 Each UDC shall pay the incentive amounts due to individual participants within 90 days of the DBP curtailment event.

2.6.3.3. Program expenses may be tracked in the memorandum account authorized to track interruptible program expenses. (Decision (D.) 01-04-006, Ordering Paragraphs (OPs) 15 and 16; D.01-07-029, OPs 2 and 3; D.02-04-060, OP 19.)

2.6.3.4. Participants will only be paid for a maximum of 150 percent of their accepted bid kW load drop measured on an hourly basis. Participants must drop at least 50 percent of their bid load drop to qualify for any payment in any hour. In no case will a customer be paid an incentive if load drop does not meet 10% of the customer's average annual demand but not less than 100 kW.

2.6.3.5 Baseline load for measuring load drop will be computed pursuant to the Voluntary Demand Response Program (VDRP) methodology.

2.6.3.6 Once a bid has been accepted, the accepted bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer’s actual performance.

2.6.4. Participation Requirements

To participate in the program, customers must meet the following minimum requirements:

2.6.4.1. Individual bids should be a minimum of 10 percent of each customer account's average annual demand, but not less than 100 kW per customer account. No aggregation of customer accounts will be allowed.

2.6.4.2. Customers must have an interval meter. For customers over 200 kW the meter will be provided pursuant to the CEC's real time electric meter (RTEM) program, based on available funding. For customers under 200 kW the meter will be provided pursuant to VDRP procedures under which expenses are recorded in a memorandum account for future rate recovery. Customers who receive meters at “no charge” will be obligated to perform in at least 10 events, if bids are requested and the customer’s bid is accepted, and remain on the program for one year consistent with existing tariff provisions of the VDRP.

2.6.4.3. DBP customers may not also be enrolled in the ISO's Demand Relief Program, the Participating Load Program, also known as the Ancillary Services Load Program, or the California Power Authority Demand Reserves Program. Customers may achieve load drop by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.

(END OF ATTACHMENT A)